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Assessment of oxyfuel power generation technologies

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ABSTRACT

In this work, a cost–benefit analysis concerning the use of oxyfuel combustion technology is carried out. For the analysis, the IPP optimization software is used in which a decouple optimization method for power technology selection in competitive markets is employed and the electricity unit cost and the CO_2 avoidance cost are calculated. The results indicate that oxyfuel technology is a competitive CO_2 capture and storage (CCS) technology. In addition, the effect of varying loan interest rates was investigated in the economic performance of an oxyfuel combustion plant. This analysis, revealed that up to a value of loan interest of approximately 5.3% the oxyfuel plant retains the competitive electricity unit costs (compared to other CCS technologies). For higher interest rate levels, other CCS technologies become more economically attractive.

Contents

1. Introduction

Carbon dioxide (CO_2) is considered to be the principal greenhouse gas responsible for global warming. Unless specific policy initiatives and measures are undertaken, global greenhouse gas emissions will rise further causing an increase to the surface temperature which will lead to irreversible and possibly catastrophic changes to the Earth's environment. The challenge presented is the global reduction of CO_2 emissions by 50–80% between now and 2050 [7].

It is widely acknowledged that CO_2 capture and storage (CCS) technologies can play an important role in mitigating CO_2 emissions. Facing this life threatening phenomenon, it is essential that CCS technologies should receive the appropriate attention required in order to constitute a promising option for gradual de-escalation of this serious problem. Already the new energy policy of the EU is focused towards the development of CCS technologies. One of the major goals of this policy is the development and operation of 12 large-scale CCS technology integrated power plants by the year 2015. This is expected to enhance the further integration of CCS technologies into existing and new conventional power plants leading to the achievement of the environmental protection target as envisaged by the EU.

Currently there are three types of CCS processes that could be incorporated in these types of plants. These are the oxyfuel combustion, the pre-combustion and the post-combustion processes. It is of course unavoidable that the capture of CO_2 in power plants will come at a price, since it will require energy from the plant. This will not only affect the cost of electricity, it will also increase the use of fossil fuel at a plant level. Pre- and post-combustion CCS technologies have been the subject of previous work [1] where it was indicated that the IGCC plant with pre-combustion CCS had the lowest CO_2 avoidance costs and, in most cases, the lower electricity unit cost. Specifically, in [1], a review of the available literature on the subject of CCS technologies and a tabular comparison of results of the respective cost–benefit

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analyses reported in each work, regarding the expected CCS technology electricity unit costs and avoidance costs, is presented.

Oxyfuel combustion of pulverized coal is a promising new technology which has been receiving significant international research attention. The advantages of oxyfuel technology are the potential for almost complete capture and sequestration of CO_2 and for being retrofitted in existing thermal power plants. In addition, oxyfuel technology combustion is carried out in an environment of pure oxygen only instead of a mixture of oxygen and nitrogen (air). This gives rise to increased CO_2 concentration in the flue gas which can be readily and economically separated from the water vapour which constitutes the remaining flue gas composition. Today, several major electric power generation corporations have already started to materialize their plans for implementation and demonstration of large-scale oxyfuel power plants.

In this work, a cost–benefit analysis for the evaluation of CCS cost by using the oxyfuel combustion process in a pulverized coal-fired power plant is carried out. For the analysis, the IPP algorithm version 2.1 (independent power producer technology selection algorithm) software tool is employed [9].

In Section 2 the oxyfuel combustion CCS process and major challenges are discussed, while in Section 3, the mathematical formulation and the optimization software are described. In Section 4, the cost–benefit analysis concerning the use of pulverized coal oxyfuel combustion CCS is presented and the results obtained are discussed and compare with those on [1]. The conclusions are summarized in Section 5.

2. Oxyfuel combustion

Oxyfuel or O_2/CO_2 recycle combustion is a relatively new CCS technology and is still at an early development stage compared to either the post- or the pre-combustion CCS technologies. However, oxyfuel technology promises to be an economical alternative coupled with the possibility of higher CO_2 capture rates.

Oxyfuel combustion is defined as the combustion of pulverized coal or other hydrocarbon fuels, in nearly pure oxygen environment instead of air which is the conventional method employed in coal-fired steam power plants. This is illustrated diagrammatically in Fig. 1. Specifically, oxygen (of 95% purity or higher) is fed to the boiler via a cryogenic air separation unit. In addition to oxygen, the major part of the CO_2-rich exhaust flue gas is also recycled back to the boiler as a form of diluent, in order to control combustion temperature and reduce NO_x formation. This is necessary, since combustion of coal in pure oxygen gives a high flame temperature which will enhance the formation of NO_x in the boiler. Pulverized coal or other hydrocarbon fuel is then combusted in this mixture of O_2 and CO_2 within the boiler [2].

The major advantage of burning coal in such a mixture instead of air is that it produces a CO_2-rich flue gas that is almost nitrogen free. This flue gas composition translates to a simpler CO_2 capture and sequestration process compared to the post- or the pre-combustion CCS technologies. This advantage is amplified by the fact that the other major component of the flue gas in oxyfuel combustion is condensable water vapour [8]. These factors can provide the foundation for an almost zero-CO_2 emission power plant (capture rate of 95% or more) [6], something that cannot at this moment be achieved in the cases of the other CCS technologies already investigated [1]. Another advantage arising from the flue gas composition, is that the reduced presence of nitrogen in the flue gas means that the formation of harmful NO_x emissions is significantly reduced and that plant equipment used for the flue-gas desulphurization and nitrogen oxide removal will be smaller in volume, cheaper and less complex than corresponding equipment in a conventional coal-fired power plant [2].

Oxyfuel combustion technology produces a flue gas that is essentially composed mostly of CO_2. Final flue gas composition at the exit of the boiler may vary depending on the type of combusted hydrocarbon fuel used (e.g., pulverized coal, dry or raw lignite). However, typical flue gas composition can be the following: 55–65% CO_2, 25–35% H_2O, the rest being nitrogen, oxygen and argon. This composition can change depending also on the moisture levels and the nitrogen composition of the fuel used, however CO_2 remains by far the principal gas [5,10,14]. Coal combustion can produce flue gas of lower water composition compared to lignite. In all cases, CO_2 sequestration and capture is achieved by the cleaning of the oxyfuel combustion flue gas using a series of cleaning processes. The final product gas is reportedly composed by as much as 96% CO_2 [5], which can then be compressed and transported for storage or enhanced oil recovery applications. The basic cleaning processes are the cooling and condensing of the water vapour and the desulphurization. However, in most cases the use of gas driers for excess moisture dehydration and the use of an inerts removal stage for the removal of the non-condensable gases such as nitrogen, oxygen and argon are also employed.

The first cleaning process of the flue gas after exiting the boiler is the particle removal process via the use of dedicated filters which are usually electrostatic or fabric. This process removes the ash present in the flue gas and it is only after this stage that a part of the flue gas can be recycled back to the boiler. The required amount of flue gas to be recycled back to the boiler can only be determined empirically. The critical factor that limits the amount of recycled flue gas is flame/burnout stability within the boiler. There are two

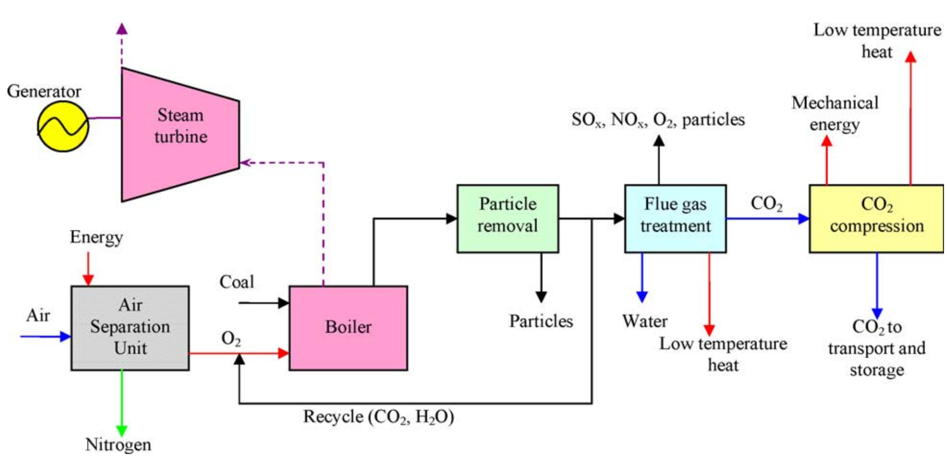

Fig. 1. Basic principle of oxyfuel technology.

major reasons for which reduced amounts of flue gas recycle should take place in the oxyfuel process. First, excess amounts of recycled CO_2 can negatively affect flame and burnout stability by decreasing flame speed and temperature. Essentially a significant increase of oxygen concentration is required in order to compensate for the higher heat capacity of CO_2 thus keeping stable flame temperature and providing a stable combustion process [4]. Second, the amount of recycling taking place in the process is inversely proportional to the oxyfuel plant efficiency. Therefore, by keeping the amount of recycled flue gas as low as possible, plant efficiency receives minimum penalization. The ideal level of recycled flue gas to the boiler is still a subject of research and under continuous investigation.

After the particle removal stage, the flue gas can be further treated for moisture removal. During this stage, the water vapour and other forms of moisture that exist within the flue gas are removed via cooling and condensation. It should be noted that the use of dry coal fuel reduces the amount of moisture and water content in the flue gas. Flue gas sulphur removal follows the condensation stage so as to ensure that there is no increased risk of corrosion in the boiler. The process is again followed by another stage of cooling and condensation (a gas drier can also be employed after the condensator for dehydrating the remaining water in the flue gas). Finally, and prior to the final stage of CO_2 compression and transportation, removal of the non-condensable gases is necessary. This can be achieved via a super-cooling of the flue gas so as to transfer it in liquid state. Thereafter, the non-condensable gases can be flashed from the liquid CO_2 [2,10].

The necessity of mixing the pure oxygen with recycled CO_2 in the boiler has already been mentioned above. Extensive research is taking place in order to minimize the concentration of recycled CO_2 in the mixture so as to increase oxyfuel plant efficiency and reduce boiler size. Circulating fluidisized bed boilers can be shown to significantly reduce the amount of flue gas recycle due to the fact that the combustion temperature can be controlled through the internal recirculation of bed material instead of the recirculation of CO_2 [2]. This is something that cannot be achieved with pulverized fuel boilers used in the conventional coal-fired plants. In a CFB boiler scenario, oxygen concentration in the O_2/CO_2 mixture can become very high (oxygen concentration of up to 70% has been reported [12]).

Another method for increasing oxyfuel plant efficiency is the substitution of the air separation unit (see Fig. 1) by other technologies for pure oxygen provision that are less demanding in terms of auxiliary power requirements. Indeed, use of the ASU has been reported to penalize plant efficiency by as much as 10% (compared to a conventional pulverized coal plant) [10], while the use of alternative technology for oxygen provision, such as ion-transport membranes may reduce this to only 3–5%. Apart from these, other oxygen provision technologies are currently the ceramic auto-thermal recovery and the chemical looping combustion [13]. However, the cryogenic air separation unit process remains the only available large-scale technology for oxygen provision at present.

Since oxyfuel technology is still at the research and development stage, no operating pilot plants have yet materialized. However, the promising preliminary results of this technology in terms of CO_2 capture have caused significant interest, and a number of oxyfuel plants are already planned to be commissioned within the next 2–3 years.

3. Mathematical formulation and optimization software

The cost–benefit analysis is carried out using the IPP optimization algorithm [9]. This user-friendly software tool takes into account the capital cost, the fuel cost and operation and maintenance (O&M) requirements of each candidate scheme and calculates the least cost configuration and the ranking order of the candidate power technologies. A brief description of the optimization procedure is given below.

In a power optimization problem the computation of the least cost power generation technology is formulated as an optimization problem, which minimizes the production cost, c, of each candidate power technology configuration, k, by optimizing the objective function,

$$\min \frac{\partial c}{\partial k} = \min \sum_{i=1}^{n} \frac{\partial A_i(C_i)}{\partial k}, \tag{1}$$

where,

$$\frac{\partial \mathbf{A}}{\partial k} = \left[\frac{\partial A_1}{\partial k}, \frac{\partial A_2}{\partial k}, \ldots, \frac{\partial A_n}{\partial k} \right]^T, \tag{2}$$

is the control variables vector with $(\partial A_i/\partial k)$ given as a function of the various cost components $(\partial C_i/\partial k)$, $i = 1, 2, \ldots, n$, of each individual candidate power technology configuration (or scenario) k, $k = 1, 2, \ldots, m$.

For the computation of the least cost power generation technology, various technologies and various different configurations can be taken into account by varying parameters such as the type of the technology, the type of the fuel, the mode of operation, etc. A typical shape of the objective function c for different scenarios (ideally infinite candidate power generation technology configurations might exist) is shown in Fig. 2. A minimum point can be either global (truly the lowest function value) or local (the lowest in a finite neighbourhood and not on the boundary of that neighbourhood). Points B, C, D and E are local but not global minima. The global minimum occurs at A.

In this paper an adaptive method for the minimization of the objective function c, Eq. (1), is developed. Each candidate power technology configuration is decoupled and the resulting optimization problems are solved separately. Then the least cost option is obtained by recombining the optimum solutions. This is illustrated in Fig. 3 where the various different scenarios (or candidate power technologies configurations) k, $k = 1, 2, \ldots, m$ are decoupled. Each scenario k is optimized separately and the local minimum a, b, c, d, e, g, h, ... is calculated. By recombining the optimum solutions, dotted line in Fig. 3, the global minimum, a, can be obtained.

The various control variables which are used for the optimization problem, Eq. (2), are developed below. The annual energy production P_j, in kWh, generated from a candidate power technology k for the period (e.g., year or week or day) j, $j = 1, 2, \ldots, N$, is given by,

$$\frac{\partial P_j}{\partial k} = 8760 \frac{\partial E}{\partial k} \frac{\partial LF_j}{\partial k}, \tag{3}$$

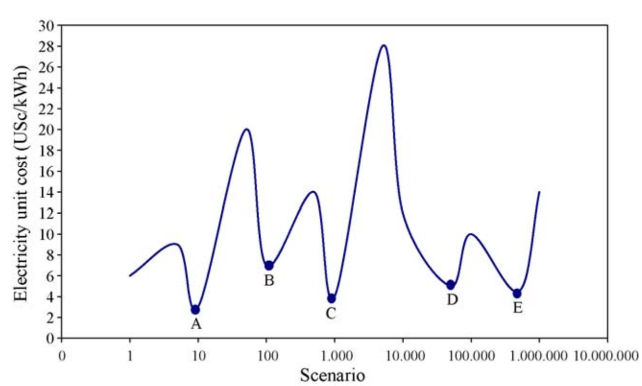

Fig. 2. Typical shape of an objective function.

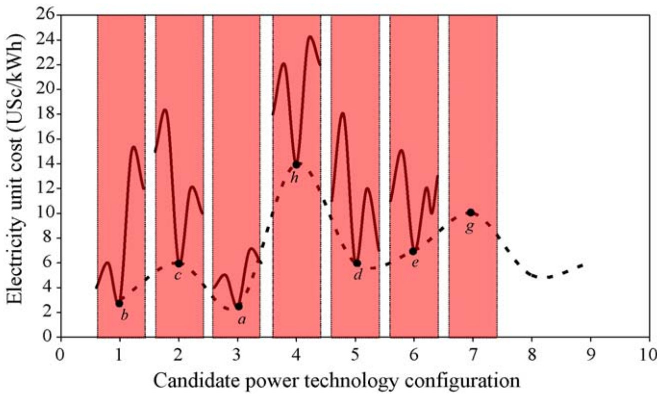

Fig. 3. Typical shapes of decoupled objective functions.

where E is the installed capacity of the candidate technology in MWe and LF is the capacity factor in %. By the adoption of the capacity factor LF_j, issues such as expected annual energy contracts with eligible customers, forced outage rate and planned maintenance can be taken into account. The annual capital expenditure C_{Cj}, in US$, is given by the relation,

$$\frac{\partial C_{Cj}}{\partial k} = q_j(1+m)^j(1+r)^{j-1}\frac{\partial E}{\partial k}\frac{\partial C_{SCj}}{\partial k}, \tag{4}$$

where C_{SC} is the specific capital cost in US$/kWh, q_j is the amortization factor per period in %, m is the loan interest in % and r is the inflation in %. The fuel cost CF_j, in US$, is given by the relation,

$$\frac{\partial C_{Fj}}{\partial k} = 3.1536 \times 10^7 \frac{\partial}{\partial k}\left(\frac{E \times LF_j \times F_j}{\eta \times CV}\right), \tag{5}$$

where F_j is the specific fuel cost in US$/t, η is the average value of the efficiency of the candidate technology in % and CV is the calorific value of the fuel in kJ/kg. The fixed operation and maintenance (O&M) cost C_{OMFj}, in US$, is given by the relation,

$$\frac{\partial C_{OMFj}}{\partial k} = 12(1+r)^{j-1}\frac{\partial E}{\partial k}\frac{\partial O_{MF}}{\partial k}, \tag{6}$$

where O_{MF} is the monthly fixed O&M cost in US$/kW. The annual fixed O&M includes staff salaries, insurance charges and fixed maintenance. The variable O&M cost C_{OMVj}, in US$, is given by the relation,

$$\frac{\partial C_{OMVj}}{\partial k} = 8760(1+r)^{j-1}\frac{\partial E}{\partial k}\frac{\partial LF_j}{\partial k}\frac{\partial O_{MV}}{\partial k}, \tag{7}$$

where O_{MV} is the specific variable O&M cost in US$/MWh. The variable O&M cost includes the spare parts, chemicals, oils, consumables and town water and sewage.

The optimum generated electricity unit cost c, in USc/kWh, in real prices is given by the objective function,

$$\min\left(\frac{\partial c}{\partial k}\right) = \min\left\{\frac{\sum_{j=0}^{N}(\partial C_{Cj}/\partial k + \partial C_{Fj}/\partial k + \partial C_{OMFj}/\partial k + \partial C_{OMVj}/\partial k)/(1+i)^j}{\sum_{j=0}^{N}(\partial P_j/\partial k)/(1+i)^j}\right\}, \tag{8}$$

where i is the discount rate. Using the control variables vector notation from Eq. (2) and substituting into Eq. (8) then,

$$\min\left(\frac{\partial c}{\partial k}\right) = \min\left(\frac{\partial A_1/\partial k + \partial A_2/\partial k + \partial A_3/\partial k + \partial A_4/\partial k}{\partial A_5/\partial k}\right). \tag{9}$$

Finally, the problem is solved in an optimum sense by minimizing the decoupled objective functions,

$$\min\left(\frac{\partial c}{\partial k}\right) = \min\frac{\partial}{\partial k}\begin{bmatrix}\left(\frac{A_1+A_2+A_3+A_4}{A_5}\right)_1\\ \left(\frac{A_1+A_2+A_3+A_4}{A_5}\right)_2\\ \left(\frac{A_1+A_2+A_3+A_4}{A_5}\right)_3\\ \left(\frac{A_1+A_2+A_3+A_4}{A_5}\right)_4\\ \cdots\\ \left(\frac{A_1+A_2+A_3+A_4}{A_5}\right)_k\end{bmatrix}. \tag{10}$$

All costs are discounted to a reference date at a given discount rate. Each run can handle 30 different candidate schemes simultaneously. Based on the above input parameters for each candidate technology the algorithm calculates the least cost power generation configuration in current prices and the ranking order of the candidate schemes.

For the purpose of the environmental analysis the annual fuel consumption indicator FI_j, in kg/kWh (fuel mass per electricity generated), is given by the relation:

$$\frac{\partial FI_j}{\partial k} = \frac{\partial}{\partial k}\left(\frac{3600}{\eta \times CV}\right). \tag{11}$$

The primary emissions annual environmental indicators U_{Wj}, in g/kWh (mass of emitted pollutant per electricity generated) are determined from:

$$\frac{\partial U_{Wj}}{\partial k} = \frac{(\partial FI_j/\partial k)(\partial S_{Wj}/\partial k)(\partial G/\partial k)}{1000}, \tag{12}$$

where S_{Wj} is the desirable concentration of the emitted pollutant (limit value based on local regulations or actual measured value) in mg/Nm^3, W refers to the type of the pollutant (either SO_2, NO_x or dust) and G is the volume of the exhaust gases per fuel mass in Nm^3/kg. The carbon dioxide environmental indicator $U_{CO_2 j}$, in g/kWh, is given by:

$$\frac{\partial U_{CO_2 j}}{\partial k} = \frac{440}{12}\frac{\partial FI_j}{\partial k}\frac{\partial X}{\partial k}\frac{\partial X_o}{\partial k}, \tag{13}$$

where X is the fuel content in carbon in %, e.g., for HFO X = 80–85% and for natural gas X = 70–75%, and X_o is the oxidation factor in %; normally taken as 0.99 (under normal combustion conditions, due to the dissociation mechanism, a small amount of carbon is partially oxidised producing CO).

In the case where a CCS system will be used the cost of carbon dioxide capture $CCS_{capture}$, in US$/t$_{CO_2}$, is calculated by:

$$CCS_{capture} = \frac{\partial c/\partial k - \partial c/\partial(k-1)}{(\partial\phi/\partial k)(\partial U_{CO_2}/\partial k)}, \tag{14}$$

where ϕ is the capture efficiency in %, k and $k-1$ refer to the power technologies with CCS and without CCS respectively and

$$\frac{\partial U_{CO_2}}{\partial k} = \frac{\sum_{j=0}^{N}((\partial U_{CO_2 j}/\partial k)(\partial P_j/\partial k))/(1+i)^j}{\sum_{j=0}^{N}(\partial P_j/\partial k)/(1+i)^j}, \tag{15}$$

is the discounted carbon dioxide environmental indicator in g/KWh. The carbon dioxide avoidance cost $CCS_{avoidance}$, in US\$/t_{CO_2} can be determined by:

$$CCS_a = \frac{\partial c/\partial k - \partial c/\partial(k-1)}{\partial U_{CO_2}/\partial(k-1) - [\partial U_{CO_2}/\partial k(1-(\partial\phi/\partial k))]}. \quad (16)$$

4. Cost–benefit analysis

In this section the technical and economic assessment carried out is presented. First, the input data and the assumptions are discussed and then the results obtained are analyzed.

4.1. Data and assumptions

The CCS technology analyzed is the pulverized coal oxyfuel combustion in a 500 MW steam plant with assumed efficiency 33.5%, a capacity generation factor of 85% and a 90% CO_2 capture rate. The boiler used is the conventional pulverized coal boiler and high purity oxygen is provided by means of a cryogenic air separation unit.

We employ IPP algorithm version 2.1 [9] with all costs updated to 2007 values. In particular, in order to simulate the specific objectives of the European Commission and the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP) [3] to have up and running CCS demonstration plants by the year 2015, the horizon of this study covers the period 2015–2049. The capital costs, including infrastructure costs were based on overnight costs of a "greenfield" plant and have been amortized for 35 years. Capital costs were taken to be 2315 US$/kW, with 4.87 US$/kW-month fixed O&M and 2.44 US$/MWh variable O&M costs. The fuel costs were based on a long term scenario with a price of crude oil of 75 US$/bbl to facilitate comparison with previous study [1]. A discount rate of 4.35%, a 5% loan interest and inflation at 2% were assumed with a 35-year payback period.

After compression, the CO_2 captured is typically transported via pipeline to be injected in pre-defined geological storage sites (deep underground saline aquifer formations, depleted oil/gas fields, voids and cavities or un-mineable coal seams). The CO_2 transport and geologic storage costs provided here (3.1 \$/t_{CO_2} and 5 \$/t_{CO_2} respectively) are estimated based on pipeline transport distance of 161 km with the CO_2 stream compressed to around 138 bar with no booster compressors [11].

4.2. Results and discussion

In this study, a cost–benefit analysis was carried out in order to identify the electricity unit cost and the CO_2 avoidance cost of a power plant using oxyfuel combustion technology compared to the cost of two conventional technology generation plants: the pulverized coal and the natural gas (combined cycle technology) combustion plants. The results of this study are then compared with the results already obtained in [1], concerning the use of four different CCS technologies namely: integrated gasification combined cycle (IGCC) with pre-combustion CCS, natural gas combined cycle with pre- and with post-combustion CCS and pulverized coal with post-combustion CO_2 capture.

The analysis showed that the CO_2 emissions indicator of the oxyfuel plant is much smaller than the emission indicator of the plants with no CSS integration. Specifically, the CO_2 emissions indicator for oxyfuel is 99 g/kWh whereas for the pulverized coal plant is 825 g/kWh and for the natural gas combined cycle of the same power capacity 403 g/kWh, that is, less than half of the emissions of the pulverized coal plant. In Fig. 4, the results from this study are compared to the respective results obtained in [1], in the case of the four different pre- and post-combustion CCS integration technologies. Even in this comparison, the oxyfuel plant retains the lower CO_2 emissions indicator amongst the other CCS plants that use coal as fuel. Specifically, the CO_2 emissions indicator of the pulverized coal plant (post combustion CCS) is 107 g/kWh and of the IGCC plant (pre combustion CCS) is 110 g/kWh. However, the CO_2 emissions from a natural gas combined cycle with pre-combustion CCS is 51 g/kWh and with post-combustion CCS is 48 g/kWh. This is due to the much lower CO_2 emissions inherent in the use of natural gas as combustion fuel.

The next analysis involved the calculation of the electricity unit cost of the oxyfuel combustion power plant. In order to maintain the comparability with the results of [1], the electricity unit cost from the oxyfuel combustion plant is calculated here in two separate stages. The first stage concerns the plant electricity unit cost up to and including the CO_2 compression stage. The second stage includes the additional post-compression CO_2 costs such as the transportation and storage costs. The resulting CO_2 avoidance cost can then be compared to the current price level of the European CO_2 emissions trading scheme.

In the case of 5% loan interest, the results obtained are shown in Fig. 5. The electricity unit cost of the pulverized coal oxyfuel combustion plant (including storage and transport costs) is

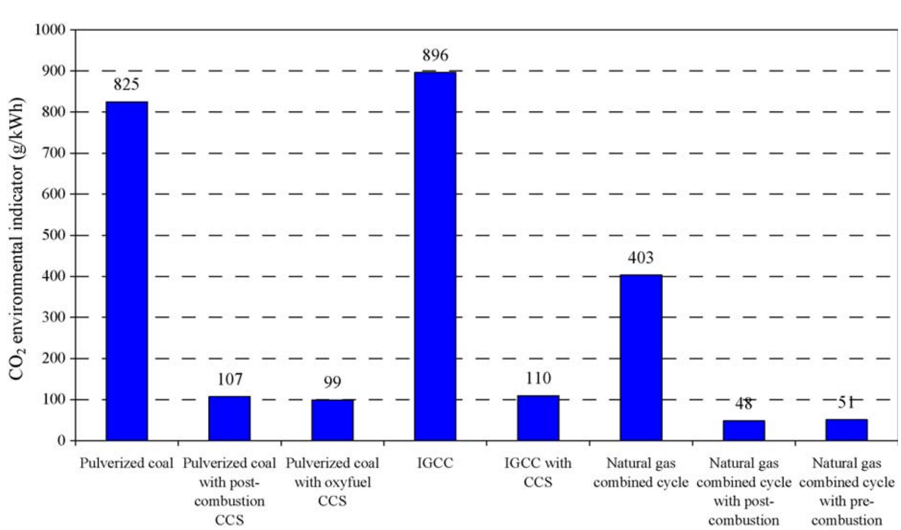

Fig. 4. CO_2 emissions from the various candidate plants.

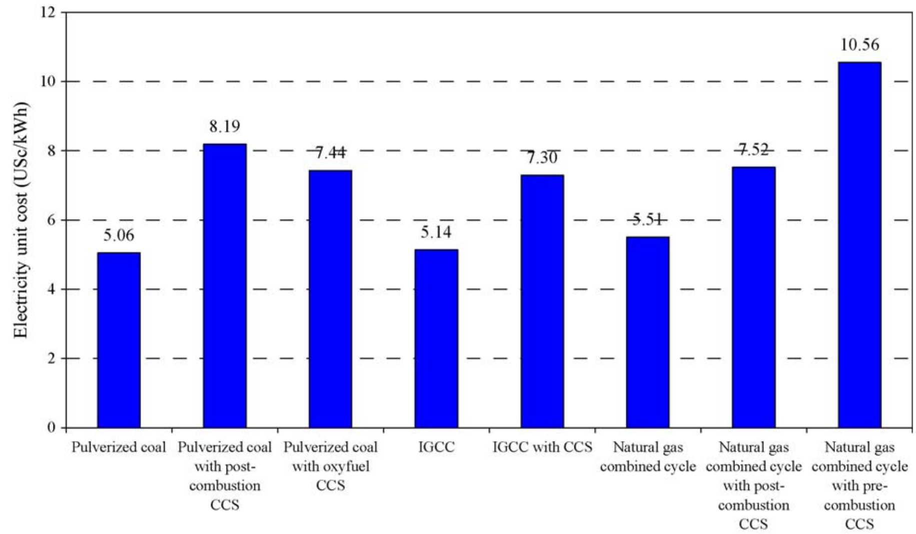

Fig. 5. Electricity unit cost including transportation and storage costs in the case of 5% loan interest.

significantly more expensive than the two conventional power plants. However, this scenario changes when oxyfuel is compared to the CCS plants already investigated in [1]. In this case, oxyfuel combustion electricity unit cost is at approximately the same level as the IGCC with pre-combustion CCS and natural gas combined cycle with post-combustion CCS power plants. It is also more economical than the natural gas combined cycle with pre-combustion CCS and the pulverized coal with post-combustion. The expected electricity unit cost from the pulverized coal oxyfuel plant is 7.44 USc/kWh compared to 7.30 USc/kWh for the IGCC with CCS and 7.52 USc/kWh for the natural gas combined cycle with post-combustion CCS. The remaining technologies are more expensive, with 8.19 USc/kWh for the pulverized coal plant with post-combustion CCS and 10.56 USc/kWh for the natural gas combined cycle with pre-combustion CCS technology. The large differences in the electricity unit costs between the various power technologies with CCS integration highlight the larger investment costs that are required in order to build and operate a natural gas combined cycle with pre-combustion capture plant compared to an oxyfuel combustion or an IGCC with pre-combustion CCS plants.

Further elaboration of the above results, highlights the fact that the natural gas combined cycle plant with post-combustion CCS has, however, the smallest incremental CCS cost than the other CCS technologies including oxyfuel. This is due to the much smaller amounts of CO_2 that are emitted from the natural gas combined cycle plant which can translate to much smaller transport and storage costs. The results concerning the incremental CCS costs are shown in Fig. 6, where for the IGCC plant with pre-combustion CCS is 2.16 USc/kWh compared to 3.13 USc/kWh for the pulverized coal plant with CCS, 2.37 USc/kWh for oxyfuel and 2.01 USc/kWh and 5.04 USc/kWh for the natural gas combined cycle with post- and pre-combustion CCS respectively.

The oxyfuel combustion CO_2 avoidance cost was then compared to the avoidance cost of the four plants with either pre- or post-combustion CCS integration [1] as shown in Fig. 7. Clearly the IGCC with pre-combustion CCS integration technology still maintains the lowest avoidance costs with 17 US\$/t_{CO_2} (or 21 US\$/t_{CO_2} if compared to conventional pulverized coal plant as reference) while oxyfuel plant is the second most economical with 23 US\$/t_{CO_2}. The pulverized coal plant with post-combustion

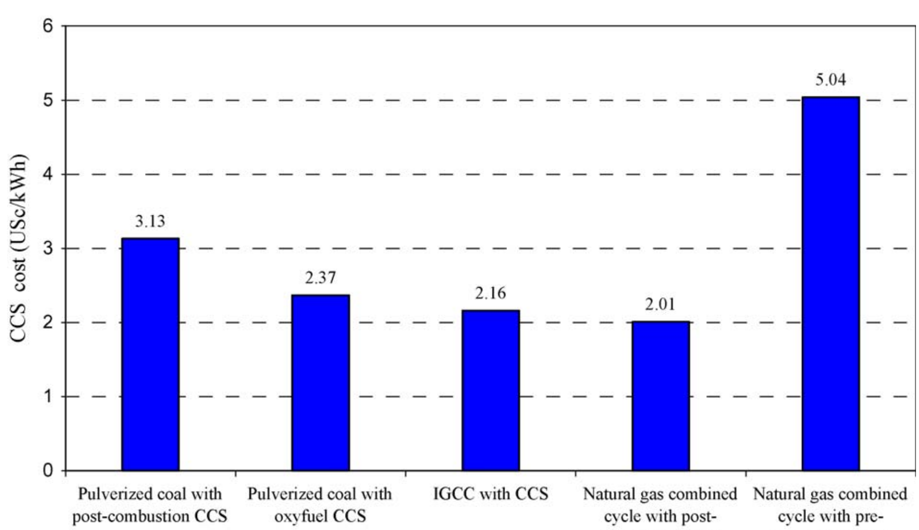

Fig. 6. CCS cost in the case of 5% loan interest.

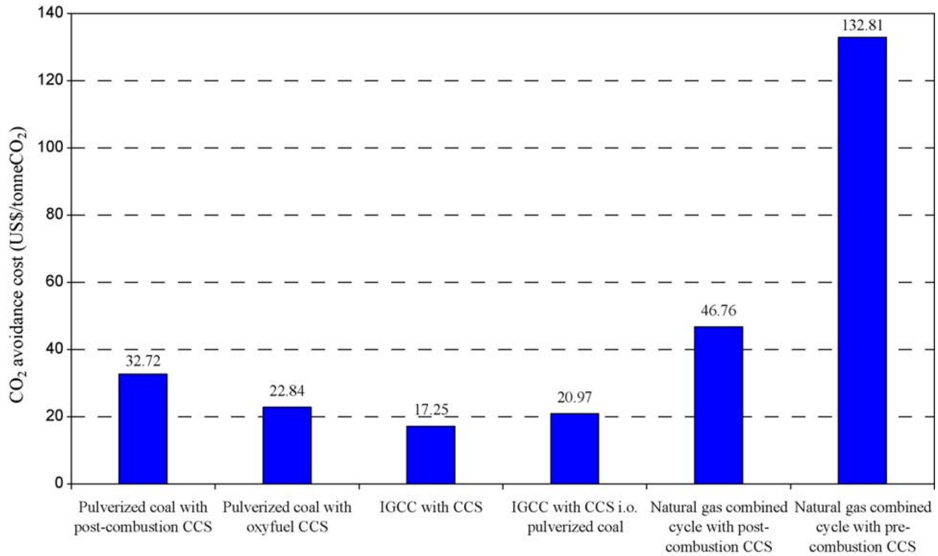

Fig. 7. Avoidance cost in the case of 5% loan interest.

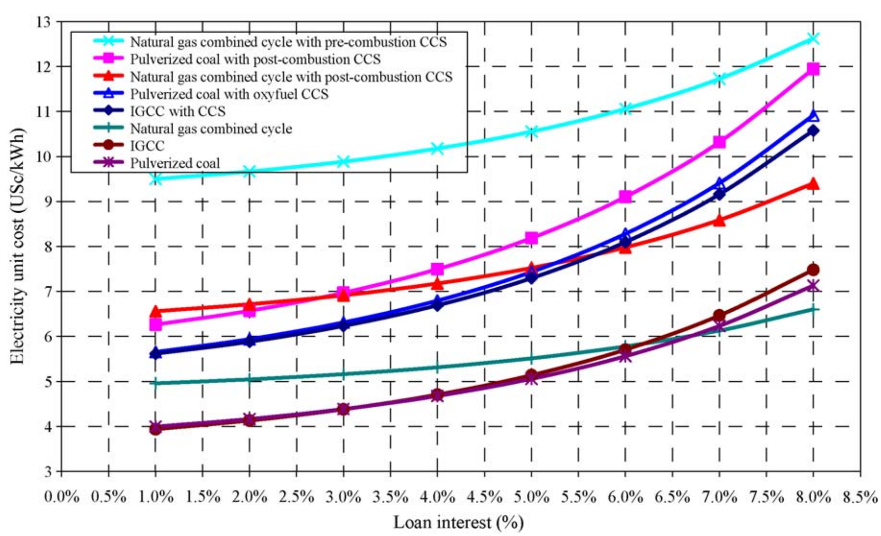

Fig. 8. The effect of loan interest on the electricity unit cost.

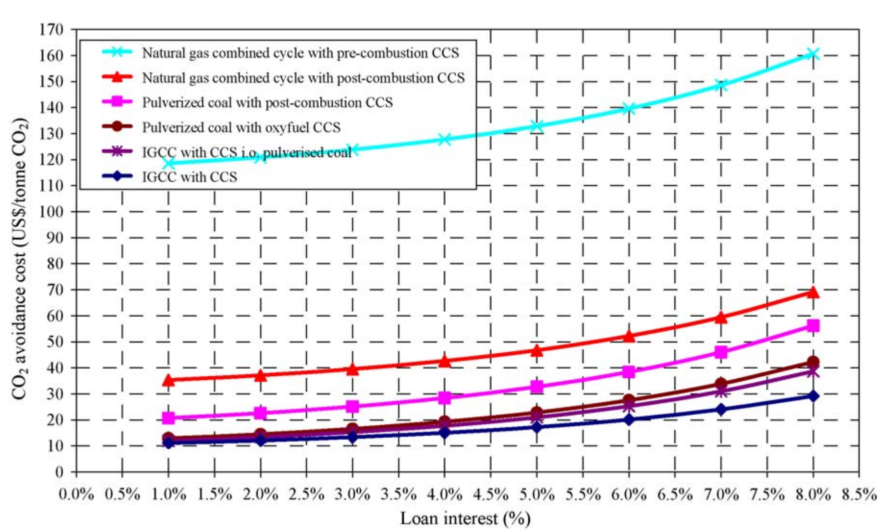

Fig. 9. The effect of loan interest on the CO_2 avoidance cost.

CCS has a CO_2 avoidance cost of 33 US\$/t_{CO_2} and the natural gas combined cycle plant with post- and pre-combustion CCS plants have a 47 US\$/t_{CO_2} and 133 US\$/t_{CO_2} avoidance cost respectively.

Further analysis was conducted using a range of loan interest rates in order to investigate the effect of loan on the economic performance of the various candidate plants. Fig. 8 shows the electricity unit cost of each technology (either with or without CCS) for various values of loan interest. It can be seen that a small change in loan interest can affect the electricity unit cost of the CCS technologies in such a way as to alter their ranking order with respect to the least cost technology.

Clearly, the least cost technologies are the IGCC with pre-combustion CCS and the pulverized coal oxyfuel combustion for loan interests up to approximately 5.3%. Beyond the value of 5.7% however, the option of natural gas combined cycle with post-combustion CCS becomes more attractive since electricity is produced at lower costs than oxyfuel or IGCC CCS plants.

In Fig. 9, the calculated CO_2 avoidance cost for each technology is provided as a function of loan interest rate. For all values of loan interest, the IGCC with pre-combustion CCS has the lowest CO_2 avoidance cost, followed by the pulverized coal oxyfuel technology and the pulverized coal with post-combustion CCS. The combined cycle natural gas with pre-combustion CCS has the highest of all CO_2 avoidance cost. The CO_2 avoidance cost of using an IGCC power plant with pre-combustion CCS instead of a pulverized coal power plant without CCS (as reference) is, also, shown in Fig. 9. This cost is slightly higher than in the case where an IGGC plant with pre-combustion CCS technology is employed.

5. Conclusions

In this study, a cost–benefit analysis was conducted for the estimation of the electricity unit cost and CO_2 avoidance cost of a pulverized coal oxyfuel combustion technology plant and compared to four different CCS technologies already investigated in previous work [1]. The CO_2 capture technologies already investigated were the pre-combustion IGCC plant, the post-combustion pulverized coal plant, and both the pre- and post-combustion natural gas combined cycle plants. The results showed that the oxyfuel combustion plant is a most competitive technology in the field of CCS. However, this technology is slightly more expensive than the IGCC with pre-combustion CCS integration technology which currently seems to be the most economical solution, having the lowest electricity unit costs and the lower CO_2 avoidance costs. The results of this study are qualitatively in close agreement with other similar studies found in the literature [6,15–17].

In addition to the above, results were obtained for a range of loan interest rates. It was shown that the oxyfuel and the IGCC plant with pre-combustion CCS remain the most economical solutions up to around 5.7% interest rate. Beyond this point, the natural gas combined cycle with post-combustion CCS provides a lower electricity unit cost for CCS applications. In terms of CO_2 avoidance cost, the oxyfuel combustion plant is second most economical after the IGCC plant with CCS across the whole range of investigated loan interest rates with an increasing margin between the two technologies as the level of loan interest rate increases.

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